The performance evaluation and design optimisation of multiple fractured horizontal wells in tight reservoirs

The Performance Evaluation and Design Optimisation of Multiple Fractured Horizontal Wells in Tight Reservoirs

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Abstract

Multiple fractured horizontal wells (MFHWs) are recognised as the most efficient stimulation technique to improve recovery from unconventional gas assets. Although multistage fracture treatment has been very successful in stimulating these reservoirs, very little work has been done on multi-stage design optimisation.

In most of the published works, the improved MFHWs design is recommended to be determined by sensitivity analysis of one variable while keeping all the other variables fixed. Several researches suggested that this optimisation should be typically performed based on economic objectives such as Net Present Value (NPV).

This paper initially describes the results of an exercise that uses statistical algorithms coupled with numerical reservoir simulations to evaluate the simultaneous impacts of important pertinent parameters on the performances of different MFHW designs at various production periods. It is shown that the impact of the individual parameter, quantified by Spearman's rank correlation coefficients technique, on different objective functions e.g. total gas production during the production period, varies depending on the governing flow regimes. For example, it is demonstrated that the impact of fracture length on the performance of MFHWs decreases over the production time while the number of fractures exhibits almost a fixed effect. It was also shown that the general trend of the importance of parameters on productivity index (PI) is similar to those observed for some of other objective functions including total gas production and NPV.

In addition, these results confirm the applicability of available well productivity models developed for the early, middle and boundary dominated flow conditions to optimise the design of MFHWs in tight reservoirs. The result of the study confirms provided maximising a desired objective in the long term (longer than the time to reaching the compound linear flow) is targeted; the pseudo-steady state productivity indices models are appropriate to be used for the design optimisation of MFHWs. Otherwise, if a shorter-term objective is targeted, this optimisation could be performed based on appropriate productivity index models available for the early or middle production

periods. These results are also confirmed by performing reservoir simulation-based optimisation of the MFHWs design using the genetic algorithm approach for various cases.

This work provides a general, fit for purpose set of guidelines, suitable for an improved well design of MFHWs in tight reservoirs. In addition, a new and easily to use workflow based on the productivity index equations is developed to optimise MFHWs design in tight gas reservoirs for a chosen targeted time while considering the practical limits and economics.

Keywords:

Performance evaluation, productivity index, design optimisation, multiple fractured horizontal wells, tight reservoirs, statistical analysis.

1. Introduction

Conventionally the formations with permeability varying between 1µD and 0.1 mD are classified as tight reservoirs. In these reservoirs, enlarged drainage area by the horizontal well with multiple transvers fractures increases the well productivity significantly. Therefore, multiple fractured horizontal wells (MFHWs) have been considered as the most efficient stimulation technique to improve recovery from such low permeability reservoirs. Fig 1 shows that the folds of PI increase due to enlarged drainage area by MFHWs with respect to conventional horizontal wells could be as large as about 12 in tight reservoirs (K_m<0.1 mD) provided that each fracture is properly cleaned up and has infinite conductivity [1, 2].

Several parameters such as formation permeability, well completion and fracture properties could affect the benefits obtained from installing MFHWs. The optimisation of the parameters such as fracture spacing, number, half-length and conductivity is necessary to ensure determining the optimum MFHWs design that delivers the maximum added-value possible. Therefore, the development of a workflow to optimise production in an efficient and practical manner is clearly desirable.

Many researchers used dimensionless fracture conductivity measure [3-5] to design hydraulically fractured vertical wells usually installed in conventional reservoirs.

In the case of unconventional reservoirs, despite the success of MFHW stimulation techniques in increasing productivity of the reservoirs and efforts directed toward their modelling and performance prediction, there is no general agreement on how their designs should be optimised particularly in tight formations. The reasons are that any decisions regarding optimum designs of MFHWs in such low permeability formations should include; 1) the impacts of mutual parameters such as fracture number, length, spacing etc., 2) the impact of existence of a relatively long transient flow, 3) the important economic considerations for potentially such as the low total production capability of the reservoirs.

In most of the published works, the MFHW's optimum design is determined by performing sensitivity analysis on one variable while keeping all other variables fixed [6-10]. Several researches suggested that this optimisation should be performed based on common economic objectives such as Net Present Value (NPV) [10-17]. This includes production forecasting by either numerical reservoir simulations, or analytical/semi-analytical models or proxy models and fracturing cost estimation.

Numerical simulation of all plausible scenarios is time-consuming, especially noting that each case requires employing a massive local grid refinement for explicit modelling of the fractures.

The problem with analytical forecasting models of MFHWs in tight reservoirs is that they do not capture all of the flow regimes (as will be discussed in Section 2) and/or requires information about the expected flow regimes during production time [7, 14, 18-20]. For instance, the methodology proposed by Meyer et al. [14] neither included any equations for capturing the compound linear flow regime around MFHWs nor considered the impacts of interference between fractures (i.e. considering complex flow regimes around MFHWs). Several of these equations have been developed based on various assumptions mainly valid in either conventional or ultra-tight formation, which are not applicable for tight reservoirs. For instance, Moradi et al. [20, 21] addressed the deficiencies of the widely-used models and developed a new flow equation to model the compound linear flow regime, the most important flow regime for characterising the fractured well and formation. In addition, it should be noted that many of the equations used are borrowed from well testing (i.e. rate constant solution) which may not necessarily be accurate for the constant pressure production strategy, which is commonly employed by the industry in these reservoirs.

Proxy models have recently been used to correlate the objective functions such as NPV to pertinent parameters for estimating their values in unconventional reservoirs [15, 16, 22]. Apart from the issues related to the accuracy of these models in predicting the performance of such complex well geometries, these approaches still require a certain number of reservoir simulations or information about the already drilled wells in the field to create the proxy models.

The more adopted trend in the industry for optimising MFHWs design is towards installing the longest possible fractures with more stages/clusters and tighter spacing in unconventional reservoirs or applying learnings from the previous successful operations in the field. This approach commonly results in higher initial production rates and a much higher decline rate later, which is easy to justify if only the short-term production objectives were considered [6, 23]. Closely spaced fractures also have some other practical disadvantages [24, 25] such as the fractures do not remain planar and influence propagation of each other [26]. These cause the final fracture configuration to be suboptimal.

Traditionally, for conventional reservoirs, the optimum design of a fractured vertical well is chosen based on the PI index at pseudo-steady (steady) state (PSS) flow conditions because of the very short transient flow regime. In the case of unconventional reservoirs, some researchers also proposed that an optimum design at PSS condition is the optimum design for the transient flow period too. Nevertheless, there is no proof to confirm whether this approach can be applicable in tight reservoirs with MFHWs, where transient flow period lasts much longer (months or years).

Here, a new approach, shown in Fig 2, is followed by applying statistical algorithms to evaluate various MFHWs design strategies while considering various objective functions at different times during a production period. Based on the results of the cases investigated, it is shown that, for example, the PSS based PI model could be used to optimise the overall performance of MFHWs provided long-term objectives are considered. In other words, the design that optimised the well performance at PSS conditions provided the best performance for the well lifetime. However, it should be noted that this design would not be the best design for any individual transient flow conditions.

Accordingly, a new workflow has been proposed to optimise MFHWs completion design in tight reservoirs. The proposed workflow replaces the commonly used economic objective functions (e.g. NPV), which are cumbersome to be calculated for individual MFHW design, by a new objective function (e.g. PI at PSS condition) that can be calculated and optimised easily. This eliminates or drastically reduces the requirement of production forecasting by reservoir simulation. In other words, this workflow can be simply implemented by well engineers in their optimum design practices, which leads to enhancing well performance while considering economic and/or the practical constraints. Below the tools, used to achieve the objectives, are briefly described first before presenting the details of this workflow.

2. Numerical Simulation

The performance of MFHWs in tight reservoirs can be explained by series of very complex flow regimes developed during the production time as shown in Fig 3. Assuming a perfect clean-up is performed [2], after passing the fracture linear flow regime, at the early times, linear flow from formation to each fracture corresponding to formation linear flow develops. If constant finite conductivity within the fracture is assumed, this flow regime could be represented in the form of bi-linear flow regime. The subsequent flow regime is early formation radial flow regime. It is most likely that the expected early formation radial flow regime will not follow due to the fracture interference effect. The fracture interference effect leads to a compound linear flow regime. At this stage, the pressure gradually shifts its orientation such that the bulk flow is linear toward the set of fractures. Eventually, pseudo elliptical flow regime may be observed. Finally, as pressure profiles reach the boundaries, pseudo-steady state or boundary dominated flow regime develops to represent the flow from further reservoir. The duration of these flow regimes would be different based on the fracture spacing, half-length and the diffusivity of the tight formation.

It should be noted that there are long transition periods between the mentioned flow regimes that produce the significant bulk of the total production. In addition, considering the practical fracture spacing, half-length and the diffusivity of the tight formation, some of the flow regimes before the PSS conditions may not be observed for all cases.

As already mentioned, the available analytical, semi-analytical models have not adequately addressed development of such complex flow regimes as they require information when each of these flow regimes develops over any production period. In other words, the starting and finishing times of each flow regimes and appropriate expressions describing the production during the long transition periods between the flow regimes are not well defined.

In this study, the numerical simulation approach was used to investigate the flow behaviour around the MFHWs. In these simulations, the pertinent parameters [fracture permeability (K_f), fracture width (W_f), fracture half-length (X_f), number of fractures (N_f) and fracture spacing (S_f)] were varied over wide practical ranges based on the Latin Hypercube sampling (LHS) method. In this exercise, a programming code, which automatically creates the required include files and stores relevant output data for each simulation, was coupled with a 3D reservoir model, developed by a commercially available reservoir simulator, to generate the required data bank.

2.1 Base Case Model Description

In this study, a 3D Cartesian grid model has been set-up in a black oil simulator which applies finite difference method to simulate a tight gas reservoir. As it is shown in Fig 4, the model has 151*151*10 grid cells with a dimension of 40*40*10 ft in the X, Y and Z directions, respectively. The gridding was selected based on a sensitivity analysis on the global grid size to avoid numerical dispersion while keeping the run time reasonable. Due to a much more complex flow behaviour around a MFHW compared to that around a conventional well, the local grid refinement (LGR), which explicitly defines hydraulic fractures in the simulation, is required to properly capture the variation of flow parameters as fluid travels from the matrix to the fractures and then to the wellbore. Another sensitivity analysis on the grid refinement was carried out to determine the optimum number of grids around each fracture. The optimum LGR around each fracture used in this study divided each parent grid into 9 subgirds in X, 4 sub-grids in Y and 1 grid in Z directions. The hypothetical tight gas reservoir produces from a horizontal well, which is placed in the centre of the model. The dry gas flows within a reservoir with an initial reservoir pressure of 7,500 psi, the average effective reservoir permeability (K_m) and porosity of 0.15. Table 1 and Table 2 provide more information on the model's properties and investigated parameters. To establish the scenarios, the following additional assumptions have been made, unless otherwise stated:

1) The reservoir formation is homogeneous.
2) The fluid is single-phase and slightly compressible.
3) Darcy Law governs the flow of fluid towards fractures and within the matrix.
4) Pressure loss along the horizontal section of the wells is assumed negligible.
5) The fractures are identical in term of physical properties such as conductivity and have been positioned vertically with constant spacing along the well and penetrating the whole reservoir thickness.
6) Considering MFHWs with cased/perforated completion has been used in this study, the flow to the wellbore is only through hydraulic fractures.
7) No geomechanics model is included in this study as it is expected that the impact not to be significant for the considered range of permeability. In other words, the formation and fracture properties do not change throughout a simulation.

It should be noted that the well length is not limited to a specific value to investigate the performance of installing a different number of fractures at various spacing.

3. Statistical Analysis of Effective Parameters

3.1 Latin Hypercube Sampling

Sampling (Experimental design) methods are widely used to efficiently sample among all the possibilities to identify the impact of important parameters. Latin Hypercube sampling is a statistical method for creating a sample of feasible collections of parameter values [27, 28], from a multi-dimensional distribution randomly, but systematically. In the context of statistical sampling, a square grid containing sample positions is a Latin square if (and only if) there is only one sample in each row and each column, as shown in Fig 5 (Right). A Latin Hypercube is the generalisation of this concept to an arbitrary number of dimensions, whereby each sample is the only one in each axis-aligned hyperplane containing it. This method ensures that the whole parameter range, considering its corresponding distribution, is represented in the sampling as it uses stratified sampling without a replacement technique. More information about this technique can be found in the work by McKay, Beckman and Conover [27].

Table 2 shows that distributions of the variables have been assumed uniform. N_f, S_f and X_f have been varied within the ranges of (1-15), (80-650 ft) and (100-1020 ft) while K_f and W_f have been changed from 2 to 8 mm and from 10 to 200 D, respectively. In this study, 1000 simulations with various MFHWs designs were generated by applying the LHS method to investigate the impact of the pertinent parameters fully. A pre-processor, i.e. a programming code, was developed to generate includes file, required for modelling different cases. Another programming code was also developed as a post processor to extract the required data and calculate appropriate outputs that cannot be provided by the reservoir simulators, for instance, calculation of cost and NPV described later in section 4.

3.2 Spearman's Rank Correlation Coefficient

The spearman's rank correlation coefficient (rho) is a quantitative measure to assess how well the dependence of two variables can be described with an either linear or non-linear monotonic relationship. In other words, if non-linear but monotonic relationships between the output and input variables are expected, the Spearman's rank is the most suitable technique to analysis such a dependency. It ranks the variables based on their values (e.g. from low to high) and measures the statistical dependency between two ranked variables as follows:

$$rho = \frac{\sum_{i=1}^{n}(X_i - \overline{X}) \cdot (Y_i - \overline{Y})}{\sqrt{\sum_{i=1}^{n}(X_i - \overline{X})^2 \cdot \sum_{i=1}^{n}(Y_i - \overline{Y})^2}} \quad \text{Equation 1}$$

where X is the ranked input variable and Y is the ranked output. If Y tends to increase or decrease when X increases, the coefficients are positive or negative, respectively, and higher value means a stronger correlation, (Fig 6). The Spearman's rank technique provides values between -1 and +1 where +1 is the perfect positive correlation and -1 is the perfect negative correlation. In addition, zero value shows that either increasing or decreasing X does not change Y. Fig 7 shows the corresponding field total gas production (FGPT) after 20 years of production for different fracture spacing (Sf) while other parameters change simultaneously by LHS. It is to note that for all these simulation the rho value was calculated as 0.485 (the last bar in Fig 9).

4. Results and Discussion

In this study, the variation of five relevant parameters (N_f, S_f, X_f, K_f and W_f) in reservoirs with various permeability values were examined. For each case, 1000 simulations with different MFHWs designs were generated by LHS to investigate the impact of these parameters fully. It should be noted this number of simulations was the optimum number based on a separate sensitivity analysis performed to make sure a full investigation of the search space. Also, the well length is not limited to a specific value to investigate the performance of installing a different number of fractures at various spacing.

Fig 8 shows the Spearman correlation coefficients between the five pertinent parameters and total gas production of the field (FGPT) values for the case with K_m=0.01 mD at different times during the 20-year production period where the minimum bottom hole pressure was limited to 4000 psi. The results illustrate that N_f is the most important parameter affecting FGPT during the entire well lifetime with almost a constant impact (rho value). As production continues, the rho value of N_f reduces from 0.76 to 0.71, when the fracture interference begins (mostly after a week for these cases). However, the value then increases to 0.73, when the compound flow condition is fully developed and becomes constant (at 0.74), when the boundary dominated flow regime is developed at the late production time. The results also show that the X_f effect reduces with time from 0.57 to 0.31, while the impact of fracture spacing is increasing from zero at the early production time of 1 day up to 0.46 at the late production time of 20 years. The graph also shows that the impacts of fracture permeability and width are small.

Fig 9 shows the Spearman correlation coefficients between the five pertinent parameters and PI values for the case with K_m=0.01 mD at different times during the 20-year production period. As Fig 9 shows, the general trend of the importance of parameters (rho coefficients) on PI is similar to those observed in the previous case for FGPT in Fig 8. That is, this Figure shows that the X_f effect decreases from 0.54 to 0.28, almost half of its initial value, over the entire 20-year production period while the impact of fracture spacing has increased from zero at the early time of 1 day of production to over 0.43 after approximately 1 year of the production and has reached to 0.47 during the boundary dominated flow period.

Fig 10 and Fig 11 show examples of delivered PI and field total gas production (FGPT) profiles over the 20-year of the well lifetime for four MFHW designs with N_f=10, W_f=0.025 ft and K_f=200 D in the reservoir with K_m=0.01 mD. Fig 10 shows that the PI is a monotonic function and the values reduce from initial high values during the transition period of the system and stabilise at constant values during the boundary dominated flow regime at the late time of the production period (after 5 years in these cases). Fig 11 illustrates the monotonically increasing profile of the FGPT function and shows that the long-term performance of two designs with 10 properly spaced fractures (S_f=600ft) are much better than those closely spaced even with much higher half-length for the cases considered.

In general, the Figures confirms the difference between short-term and long-term performances of the wells. The results show that the long-term performances (their rankings) of all the considered cases became unique after fracture interferences time, which is around 100 days in these cases. To best knowledge of the authors, there is no equation that calculates this time. However, the start time of compound linear flow regime that follows can be approximated by the following Equation:

$$\mathrm{t} = 237\frac{\emptyset \mu C_t S_f^2}{K_m} \qquad \text{Equation 2}$$

where $\emptyset$, μ, C_t and t are the porosity, viscosity, total compressibility and the start time of fracture interference respectively.

It should be noted that the start time of the fracture interference is always earlier than the start time of compound linear, and during the lengthy transition period in between the linear and compound flow regimes in such low permeability reservoirs.

In other words, for instance, the case with (X_f=100 ft and S_f=600 ft) is the design with better performance at PSS conditions, started performing better after the end of compound linear flow than the design (X_f=1020 ft and S_f=80 ft) which had performed better at the earlier time of production.

In addition to technical, economic considerations were included and the above graphs were regenerated based on Discounted Cumulative Gas Production (DCGP), Net Present Revenue (NPR) and NPV calculated by Equation 3, Equation 4 and Equation 5, respectively.

$$DCGP = \sum_{j=1}^{n} \frac{(Q_g)}{(1+\mathrm{i})^{\mathrm{j}}} \quad \text{Equation 3}$$

$$NPR = \sum_{j=1}^{n} \frac{(Q_g)R_g}{(1+i)^j} \quad \text{Equation 4}$$

$$NPV = NPR - \left(\sum_{k=1}^{M} (C_{well} + C_{frac})\right) \quad \text{Equation 5}$$

where i, n, R_g and Q_g are the interest rate, number of years of production, the estimated gas price and gas production (MScf). NPR is the revenue from the fractured well and M is the number of wells, which is one in this study. C_{well} and C_{frac} are the cost of drilling a horizontal well and the fracturing operation respectively and obtained based on the example cost listed in Table 3.

Fig 12 and Fig 13 show the rho values when DCGP and NPR with typical interest ratio of 0.1 and \$3 per Mscf gas were used for 20 years of the production. In both cases, almost similar trends (i.e. rho coefficients) to those obtained in previous cases are observed. The same trends were observed when interest ratios of 0.2 and 0.3 were also applied.

Fig 14 shows the rho values between the five pertinent parameters and NPV values at different times during the 20-year production period in the reservoir with K_m=0.01 mD. It is noted that the rho values at the early time of production (less than 1-year production) are influenced by the cost of the operation, but the later trends are like those observed for the previous indicators already discussed. For example, the rho value of 0.70 and higher for N_f during most of the production time (after 1 year of production) indicates that the number of fractures is the most important parameter for maximising NPV.

It should be noted that here there was no limit on the production in this study, whereas, in reality, the rate of production in the early times of production is often limited by surface facility capabilities. This would suggest that the impacts of placing longer fractures at the early days of the production would be even less when such constraints are applied.

This exercise was repeated for other cases under different conditions at the range of considered parameters in Table 1, for instance, the reservoir with lowest formation permeability (K_m=0.001 mD) in tight formation category.

Fig 15 shows the rho values between the pertinent parameters and FGPT values at different production times during 50 years well lifetime when formation permeability is 0.001 mD. The results again show that N_f is the most important parameter affecting FGPT regardless of the various flow regimes occurring throughout a well lifetime. Similar to the case of K_m=0.01 mD, the impact of X_f (and S_f) reduces (increases) with time, albeit to a different extent. That is, the effect of X_f decreases from 0.61 at the early time of 1 week of production to 0.38 at the late time of 20 years of production while the impact of S_f increases from zero at the early days up to 0.44 at the late time of production. Compared with the results of the case with K_m=0.01 mD, the impact of increasing fracture half-length has increased by about 20%, on average, for the entire well lifetime of the reservoir with K_m=0.001 mD. Also, the time that S_f becomes more important than X_f is about 5 years for K_m=0.001 mD, while it is 1 year for K_m= 0.01 mD due to a longer period of the formation linear flow regime.

It should be noted that if the permeability of the formation decreases, the boundary-dominated flow will develop later assuming same drainage area for the well. However, in practice, as the common development strategy in lower permeability reservoirs is to increase the number of wells; i.e. decreasing drainage area of a well, this results in a reduction of the transient flow regime time.

Fig 16 shows the performances of two MFHWs completion designs with the same number of infinite conductivity fractures (N_f=15), but different configuration, stimulated over a fixed contact area of 52.5 acres in a reservoir with K_m=0.001 mD. For the first case, 15 fractures were placed with X_f=1020 ft and S_f=80 ft (the largest X_f and the lowest S_f used in this study). For the second case, the 15 fractures with fracture half-length of X_f=260 ft (a quarter of the previous case) were placed four times further (S_f=320 ft) compared to the previous case. The Figure shows that although the early production is accelerated by installing longer fractures, the case with bigger S_f and much shorter fractures delivers 30% more total gas production over 20 years of production.

Two other MFHWs designs (case 1: N_f=10, X_f=1960 and S_f=320 and case 2: N_f=25, X_f=760 and S_f=120), induced with a constant volume of proppant and well length, were also considered for the same reservoir and K_m=0.001 mD with results shown in Fig 17. The Figure indicates that the case with more N_f, even with much shorter fractures, produce 45% more total gas production than the case with larger X_f and more spaced fractures. All these results contradict the more common industry practice of placing longer fracture length, which is based on short-term production period objectives.

5. Optimisation of Design of MFHWs in Tight Reservoirs

5.1 Simulation Based Optimisation of MFHWs Design

In addition to the above analyses, Level-set optimiser that is a version of Genetic Algorithm (GA) was applied to determine the optimum MFHW design. The optimisation of MFHWs design was performed to maximise the NPV value of the well after 20 years of production in the reservoir with K_m=0.01 mD. As shown in Fig 18, a sufficient number of iterations (340 runs) were attempted by the optimiser to allow the algorithm to determine the optimum design. Fig 19 shows the PI values, corresponding to the PSS conditions, of the attempted runs by the optimiser. It shows the same trend as that illustrated for NPV in Fig 18. In other words, where the PI value increases, its corresponding NPV value is increased too and vice versa. The optimum MFHW design with N_f=15, X_f=1020 ft and S_f=600 ft deliveries NPV of 14.8 Million$ and PI of 1.457 (Mscf/D.psi).

In summary, similar trends as those of the Spearman correlation coefficients for the objective functions (PI, FGPT, DCGP, NPR and NPV) are observed. This similarity and the monotonic relationships between the input and output parameters of MFHWs in tight reservoirs confirm that if a MFHW design maximises PI of the boundary dominated flow regime, it maximises the objective functions over a long enough production time in a tight reservoir for the range of conditions considered. However, this approach may not deliver the optimum design if very short-term objectives (before the start of compound linear flow) are considered. For such scenarios, an appropriate PI model for a transient flow period should be used to optimise the MFHW design for maximising a chosen objective function at the targeted time.

The results of these analyses confirm that calculating cumbersome economic objectives such as NPV is not necessary and using PI models is appropriate to optimise the MFHWs design in tight reservoirs. The selection of PI model depends on the targeted time to maximise any common objective functions.

5.2 PI-Based Optimisation Workflow

As already mentioned, it is statistically proven that PI at PSS conditions could be used to optimise the performance of MFHWs for the whole production period even though transient flow regimes may last for a considerable, long period provided the targeted time for maximising the desired objective is long enough (i.e. after fracture interference).

Applying the learning of the previous analyses, a workflow is developed to optimise PI values. Although there are several equations to calculate PI of MFHWs at PSS conditions in tight reservoirs, they have drawbacks. In this study, as maximising long-term objectives was considered, the empirical PI equation proposed by authors [29] which can predict PI of MFHWs under pseudo-steady state conditions in tight reservoirs, was used. This workflow uses GA as optimisation algorithm to optimise the variables (N_f, S_f, X_f, K_f and W_f) related to the design of MFHWs while maximising PI. The workflow considers constraints such as maximum proppant volume and/or budget etc. to deliver a practical, optimum MFHW design.

An optimisation study for a case with assumed maximum proppant volume of 15000 ft^3 and budget of 2.5 MM$ was performed while maximum length of the well was constrained to 4500 ft in the reservoir with K_m=0.1 mD. The well and fracking cost were calculated based on the data in Table 3. The spacing and half-length were limited to maximum 1000 ft and 2000 ft and minimum 10 ft and 40 ft respectively in this case. The other parameters were restricted to the range defined in Table 2. The costs were calculated based on the prices listed in Table 3.

The optimum design was found to be the MFHW with N_f=8, X_f=1172 ft, S_f=583 ft, W_f=0.008 ft and K_f= 200 D. The maximum delivered PI was 11.233 MScf/Day.psi in this case.

6. Summary and Conclusions

In this study, results of numerous numerical simulations have been combined with statistical approaches to provide a better understanding of the performance of MFHWs. It specifically examines the applicability of PI to optimise the design of MFHWs in tight reservoirs under the considered prevailing conditions. Accordingly, a practically attractive workflow for determining optimum MFHWs design in tight reservoirs is proposed. The followings key findings can also be pointed out:

1. There were similarities in the trends of the Spearman correlation coefficients for various cases and objective functions (PI, FGPT, DCGP, NPR and NPV) considered here. That is:
    a. the number of fractures was the most important parameter influencing these objective functions over the entire well lifetime with an almost constant impact.
    b. the fracture spacing had bigger impact on the late time of production while the half-length impact was more effective at the early time of production. The impacts of K_f and W_f were small throughout the production period.
2. These similarities, as well as the monotonic relationships between the inputs and outputs parameters for the studied cases, suggested that if a MFHW design maximises PI at PSS conditions, it would maximise any objective functions in the tight reservoirs provided the targeted time for maximising the desired objective is long enough (i.e. after the start of compound linear flow).
3. The optimum design determined based on the PI at PSS condition may not achieve the best possible performance at the transient flow conditions, but it would exhibit the best overall performance over the whole well lifetime.
4. The results of this study eliminate necessities of performing the lifetime performance prediction of the MFHWs by either numerical simulation or analytical modelling for determining the optimum MFHWs design in tight reservoirs.
5. A new workflow that uses PI equations was developed to optimise MFHW designs while considering the practical limits and economics.

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Nomenclature:

h	Formation thickness	PI	Productivity index
HWs	Horizontal wells	P_{wf}	Flowing Bottom-hole pressure

K_m	Matrix permeability	Q_g	Gas production rate
K_f	Fracture permeability	S_f	Fracture spacing
LGR	Local grid refinement	W_f	Fracture width
LHS	Latin Hyperbolic sampling	X_e	Drainage half-length in X direction
K_m	Matrix permeability	Y_e	Drainage half-length in Y direction
MFHWs	Multiple fractured horizontal wells	μ	Viscosity of the fluid

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Table 1: Reservoir Parameters.

Parameter	Value	Unit
Initial Reservoir Pressure	7500	psi
Min Bottom hole Flowing Pressure	3000-5000	psi
Reservoir Permeability	0.001-0.1	mD
Reservoir Temperature	200	ºF
Reservoir Porosity	0.15	
Rock Compressibility	3.82E-6	psi
Reservoir Depth	14800	ft
Well Diameter	4.5	inch

Table 2: Fracture parameters and their variation ranges.

Parameter	Min	Max	Distribution	Unit
Number of Fractures (N_f)	1	15	Uniform	
Fracture Spacing (S_f)	80	650	Uniform	ft
Fracture Half-Length (X_f)	100	1020	Uniform	ft
Fracture Width (W_f)	2	8	Uniform	mm
Fracture Permeability (K_f)	10	200	Uniform	Darcy

Table 3: Fracture and operating costs [10].

		X_f<250 ft	X_f>250 ft
C_{frac}	Fixed cost ($)	25,000	100,000
	Fracture Cost ($)	300	+100$ per extra ft
		L_w<1000 ft	L_w>1000 ft
C_{well}	Fixed cost ($)	1,500,000	2,000,000
	Drilling Cost ($)	500	+100$ per extra ft

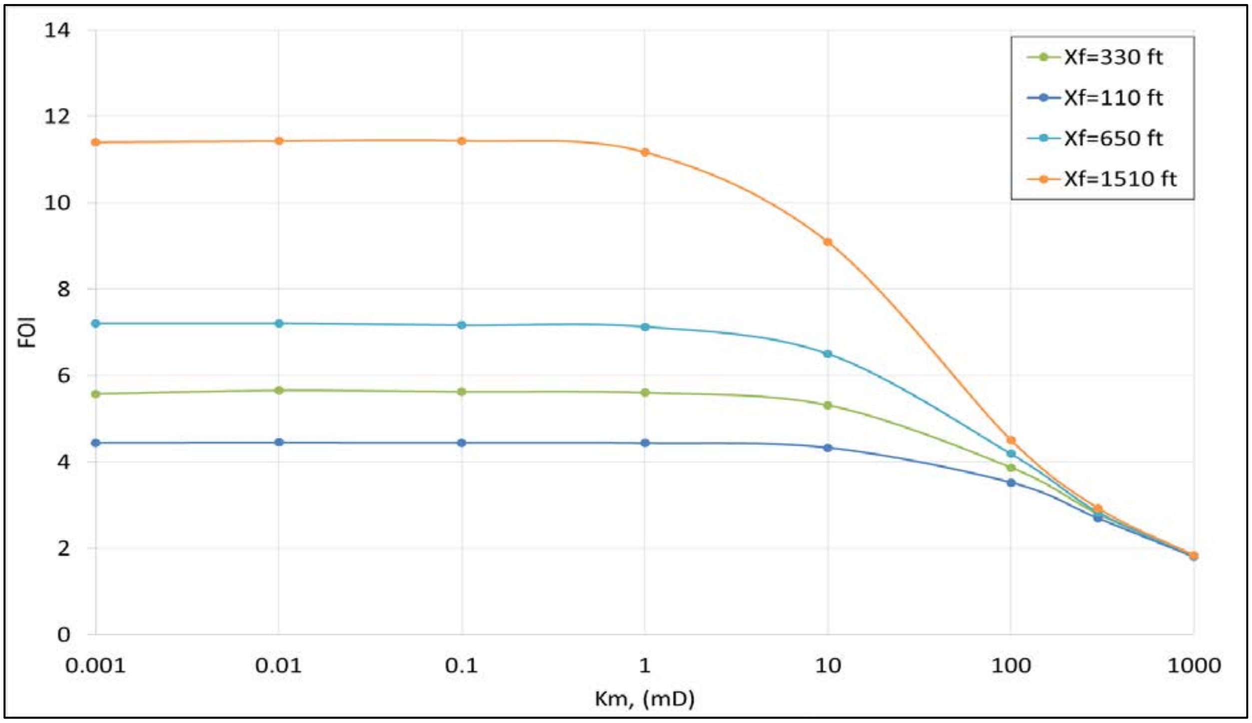

Fig 1: Folds of PI increase (FOI) versus matrix permeability for various Open-hole MFHWs completion with infinite conductivity and N_f=5 in an anisotropic formation (K_v/K_h =0.1).

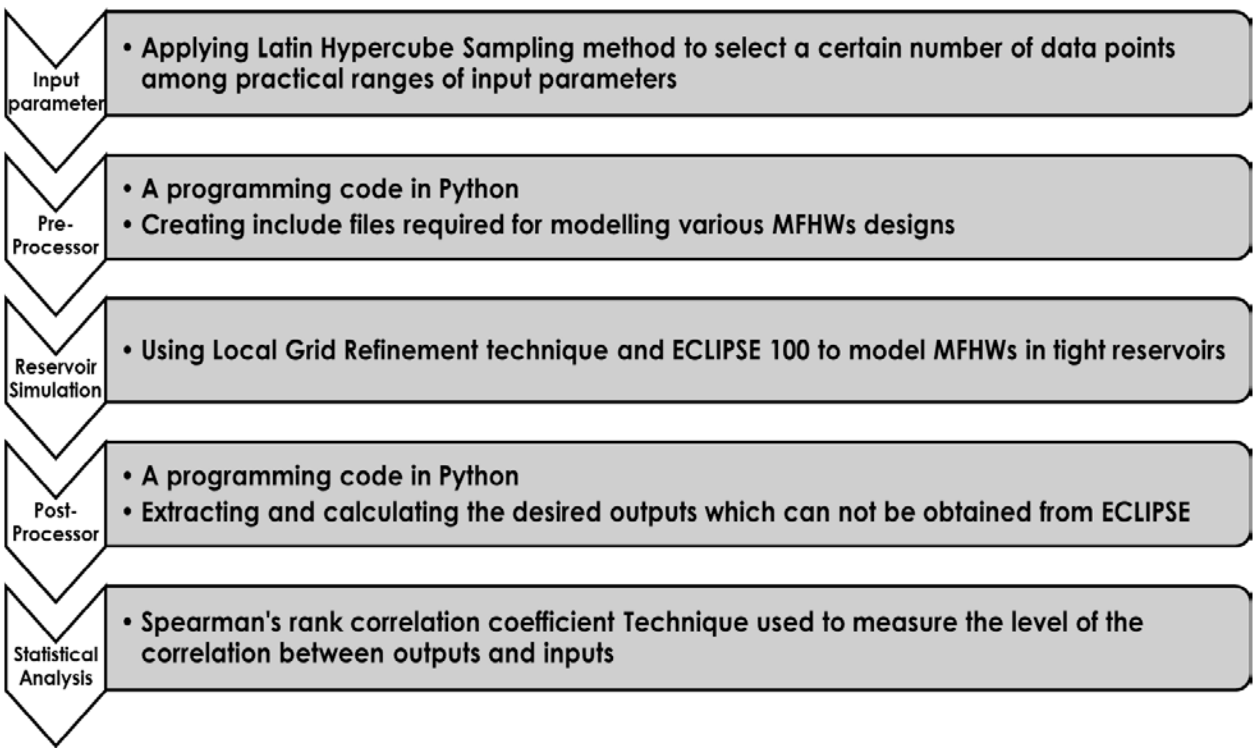

Fig 2: The sequence of steps followed to produce the sample experiments

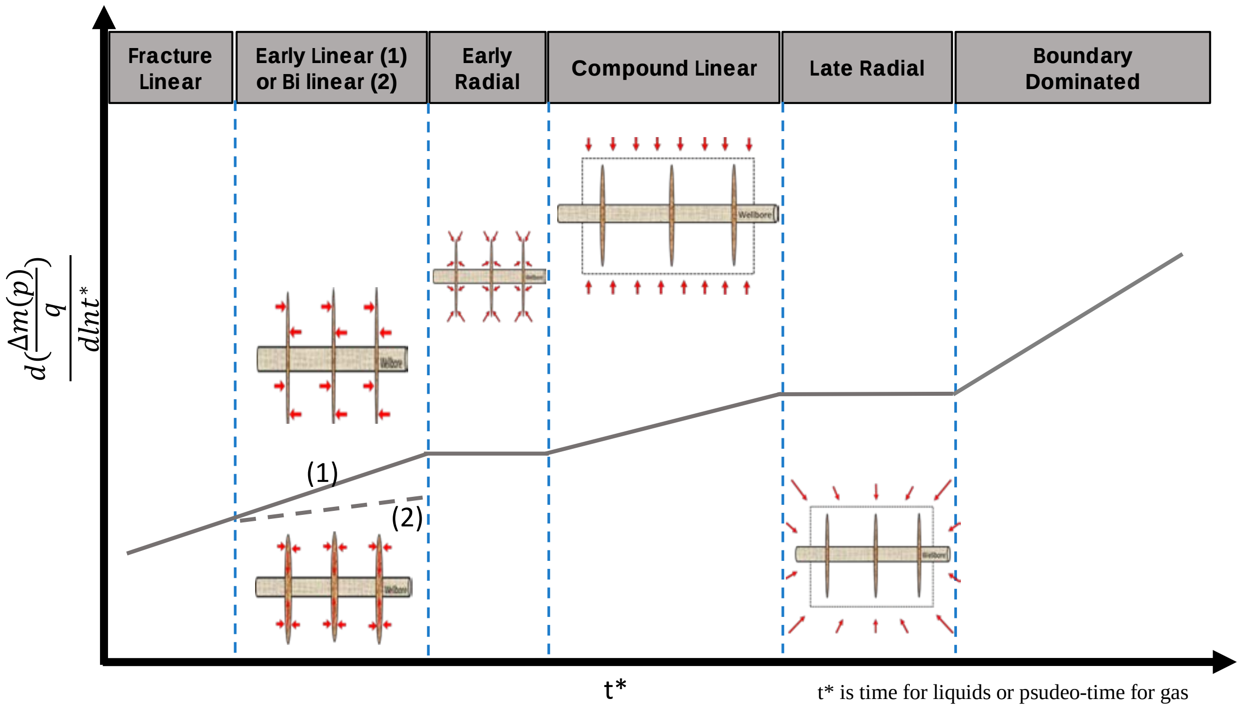

Fig 3: Schematic diagram illustrating the theoretical flow regimes sequence for a MFHW.

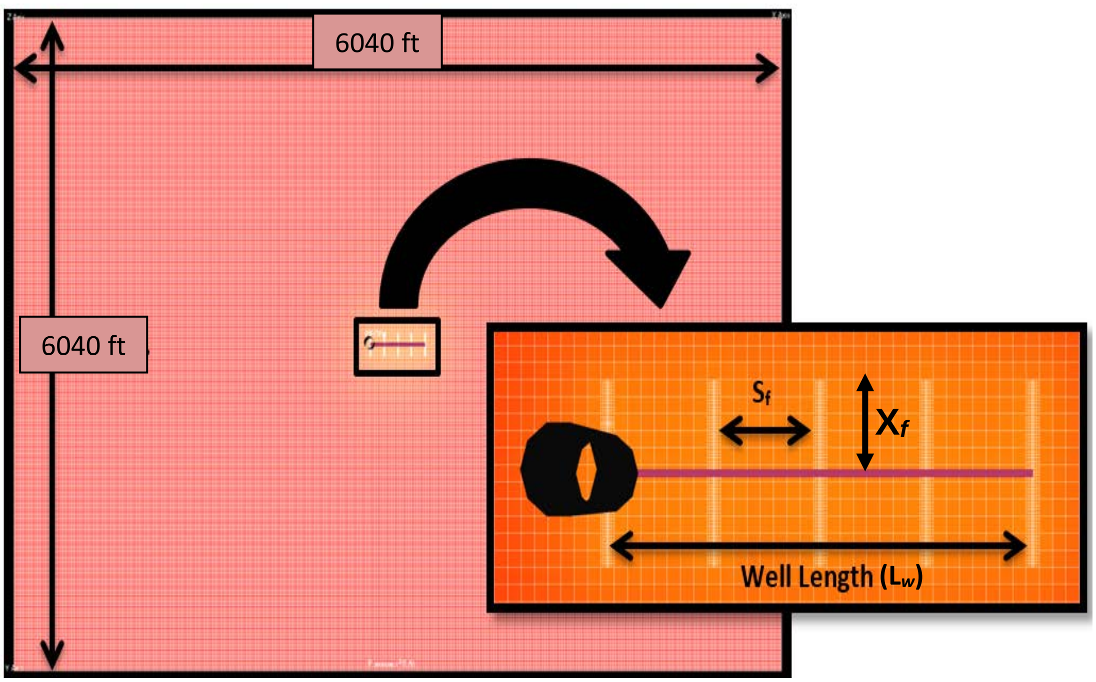

Fig 4: The simulation model used in this study.

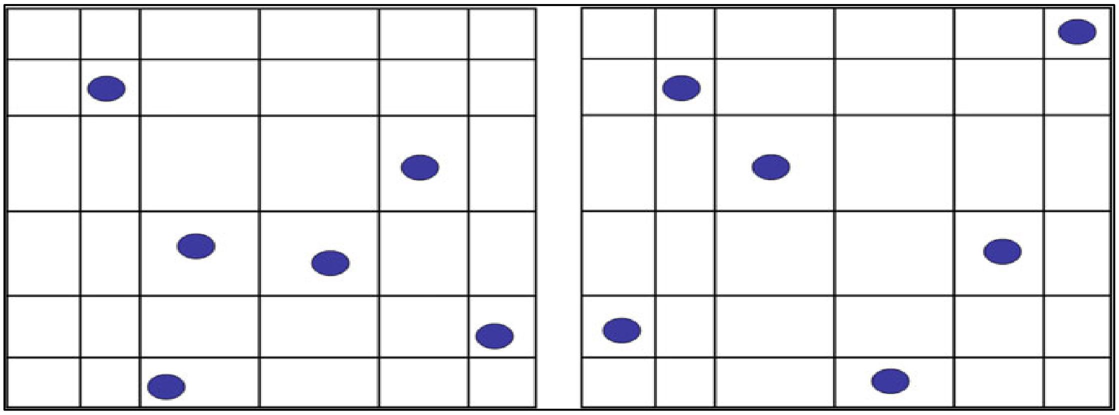

Fig 5: Examples of a square grid containing sample positions generated at random without any constraint (left) and of a Latin square where only one sample is contained in each row and each column (right).

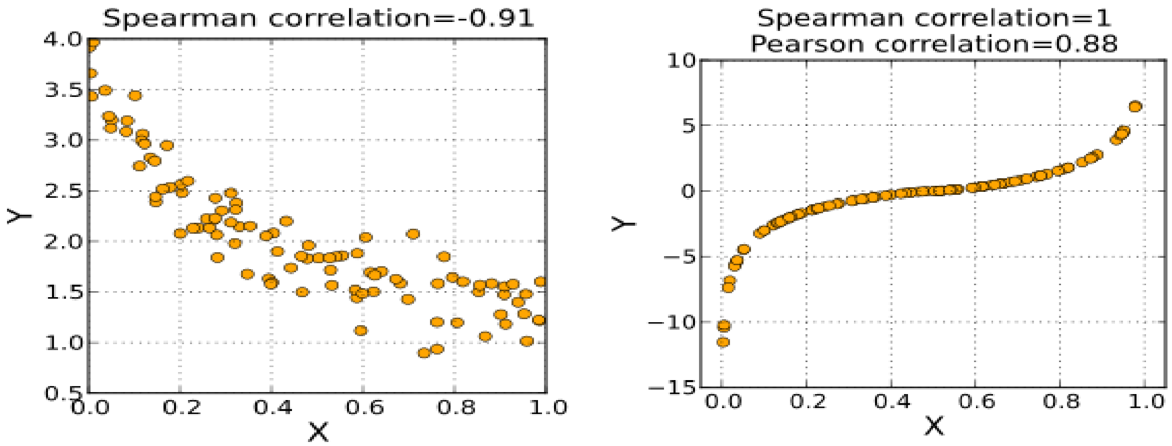

Fig 6: Examples of Spearman correlation coefficients.

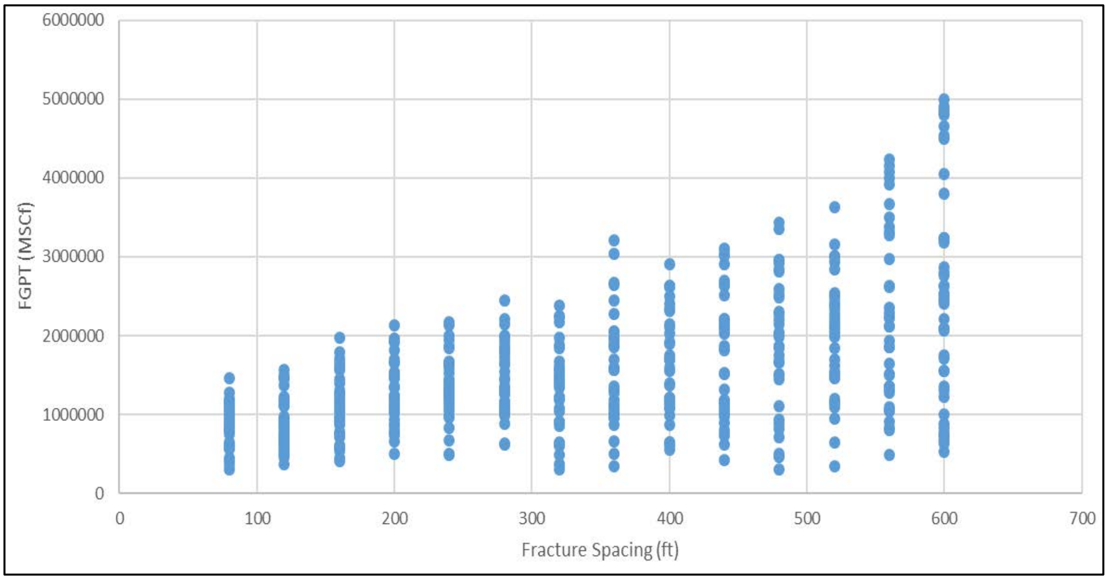

Fig 7: The total gas production (FGPT) after 20 years of production) for different fracture spacing (S_f) while other parameters changed simultaneously, K_m=0.01 mD.

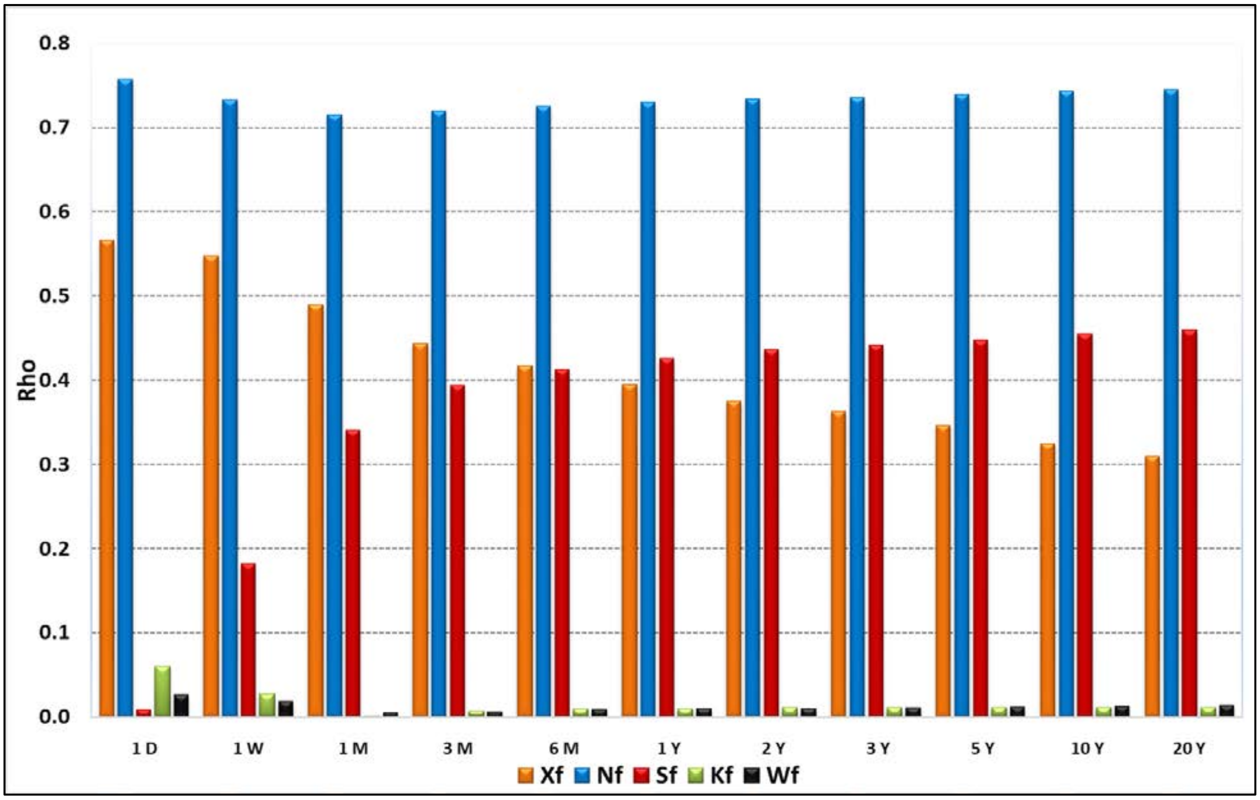

Fig 8: The impact of five pertinent parameters on FGPT values over the 20-year well lifetime (K_m=0.01 mD).

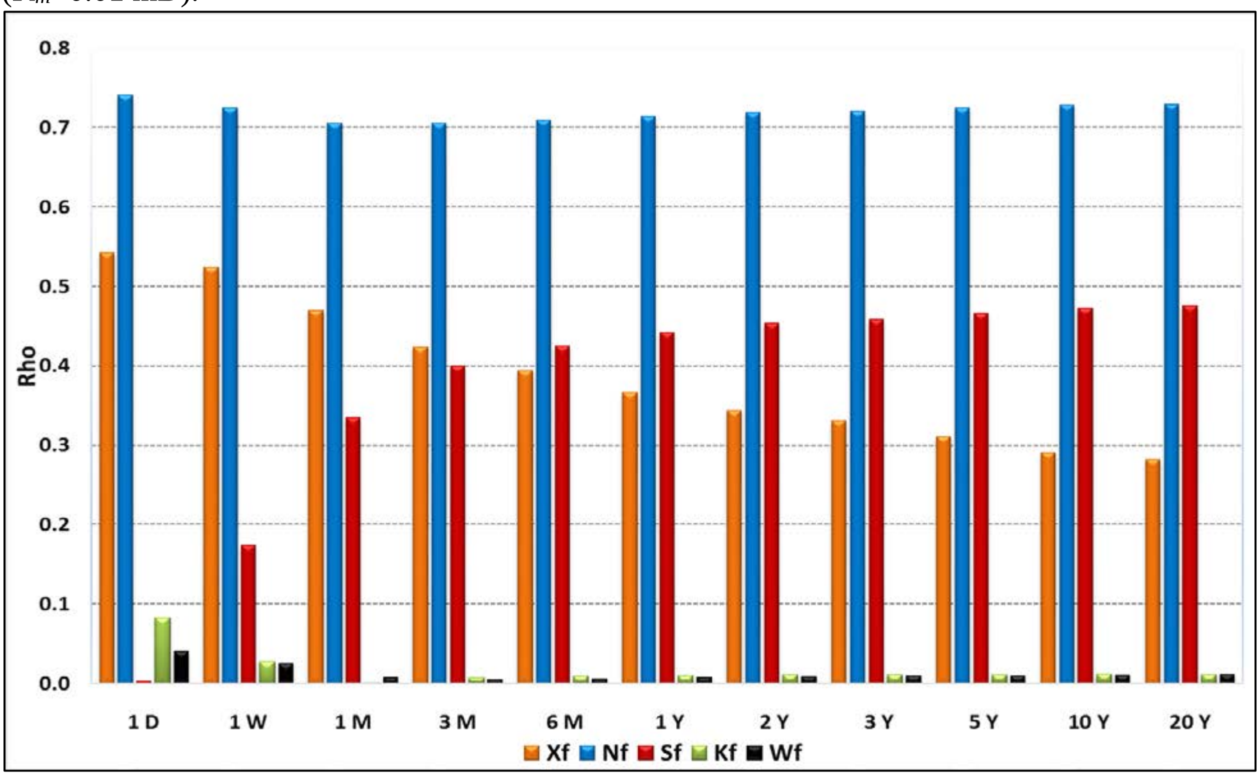

Fig 9: The impact of five pertinent parameters on PI values over the 20-year well lifetime (K_m=0.01 mD).

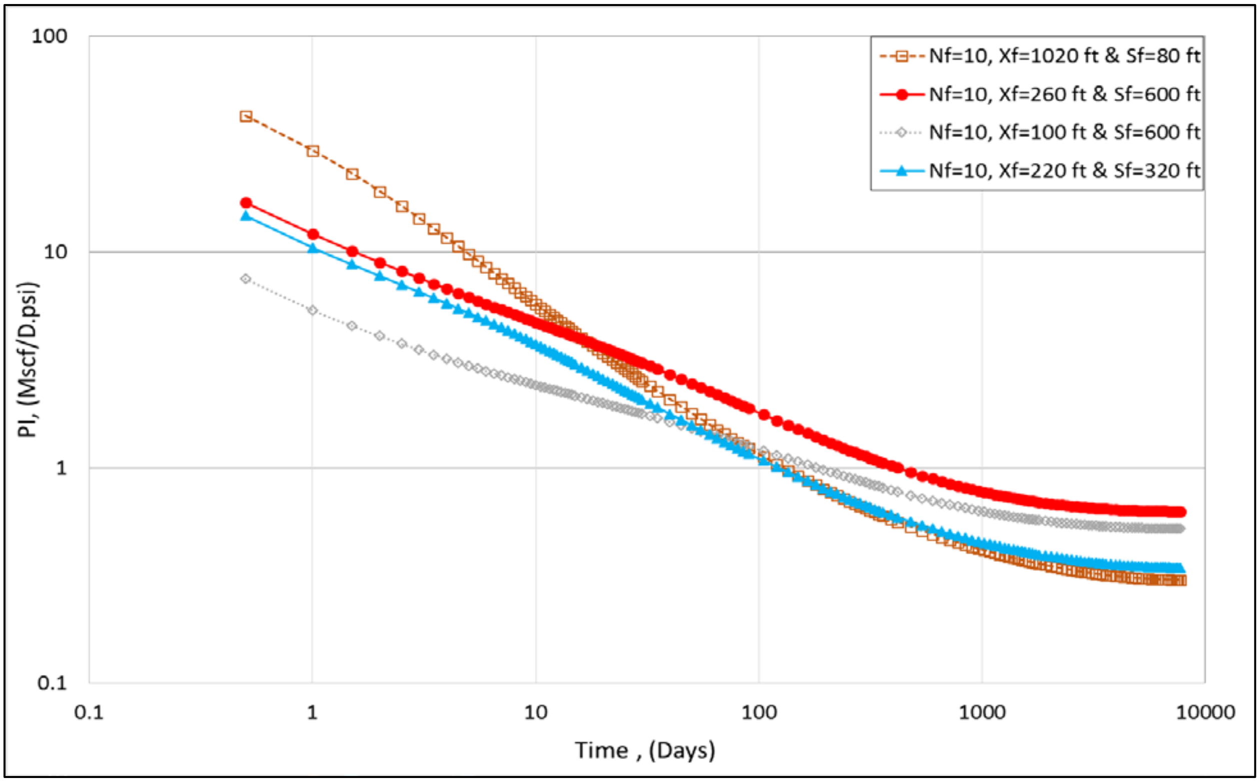

Fig 10: PI values of four MFHW completion designs over the 20-year well lifetime (K_m=0.01 mD, K_f=200 D, W_f=0.025 ft).

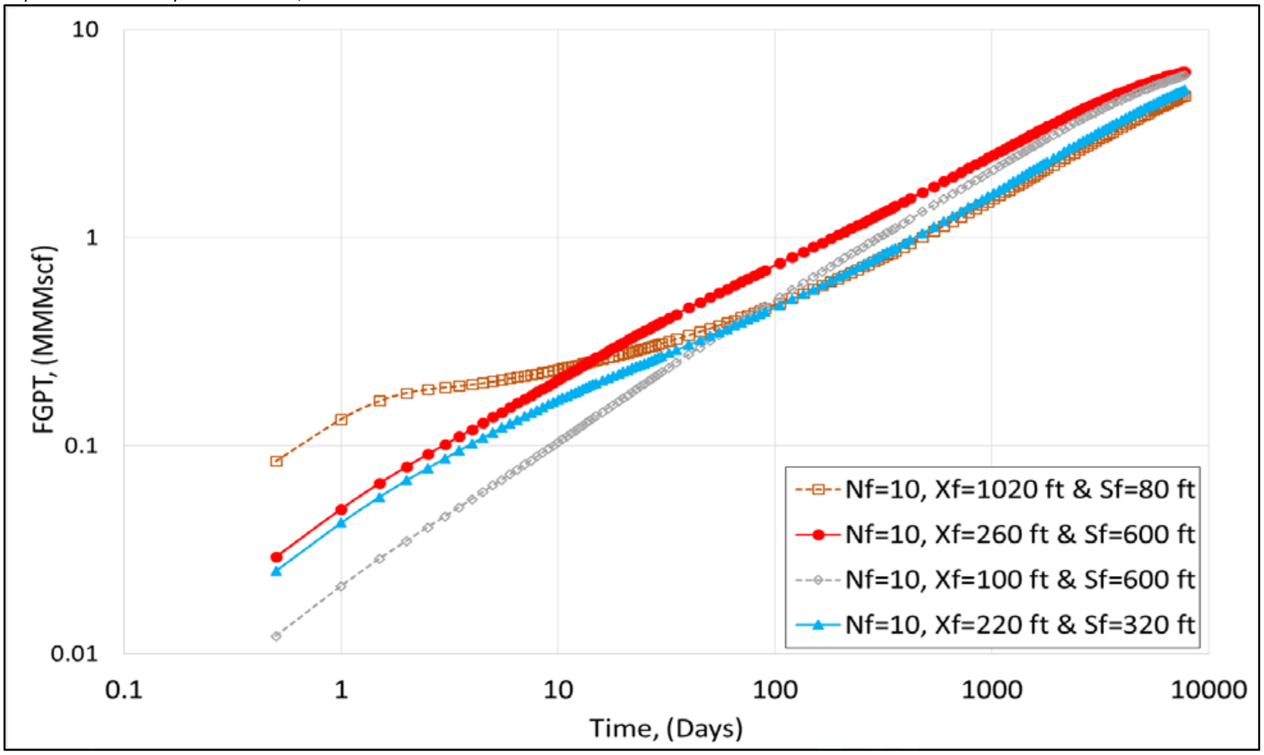

Fig 11: FGPT values of four MFHW completion designs over the 20-year well lifetime (K_m=0.01 mD, K_f=200 D, W_f=0.025 ft).

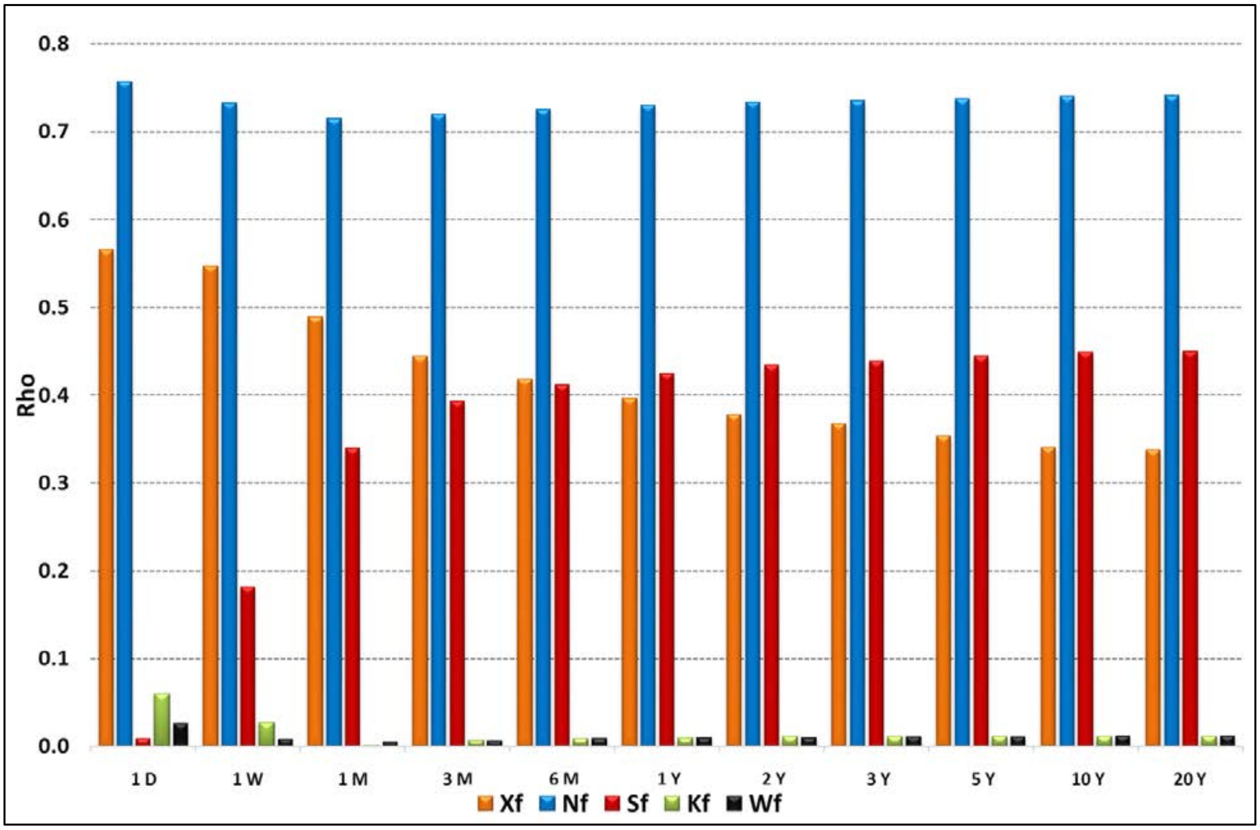

Fig 12: The impact of five pertinent parameters on DCGP values over the 20-year well lifetime (K_m=0.01 mD).

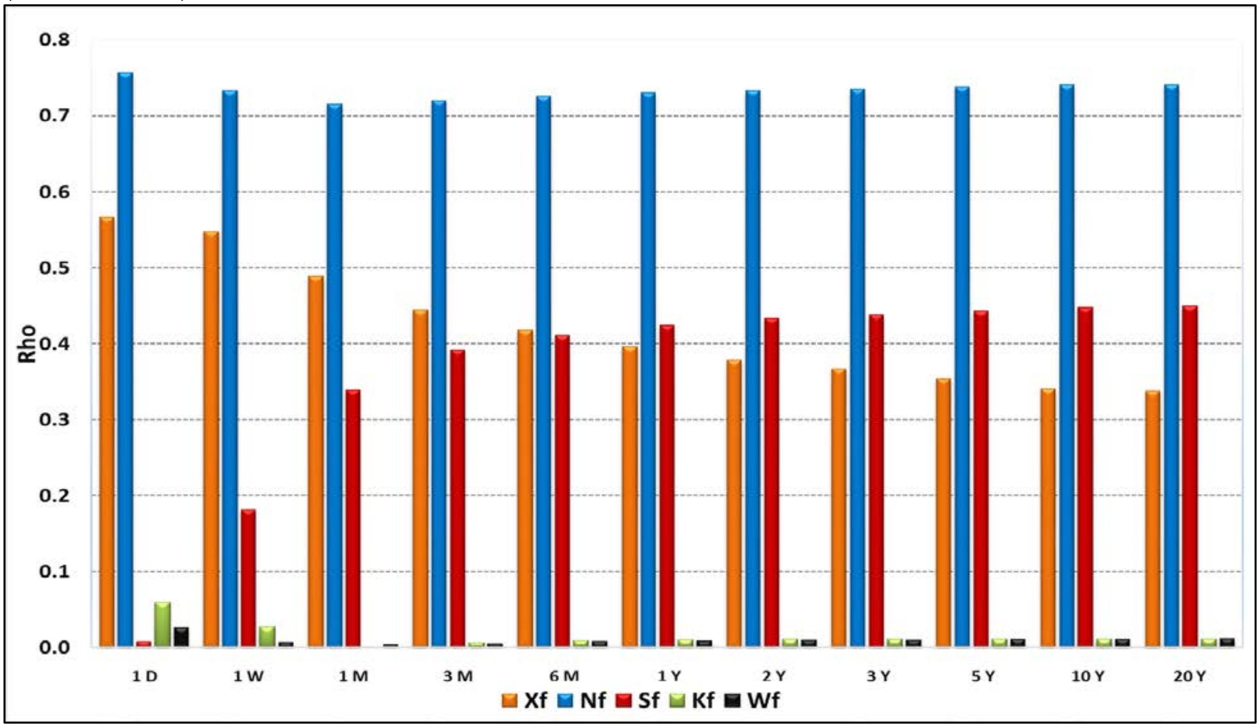

Fig 13: The impact of five pertinent parameters on NPR values over the 20-year well lifetime (K_m=0.01 mD).

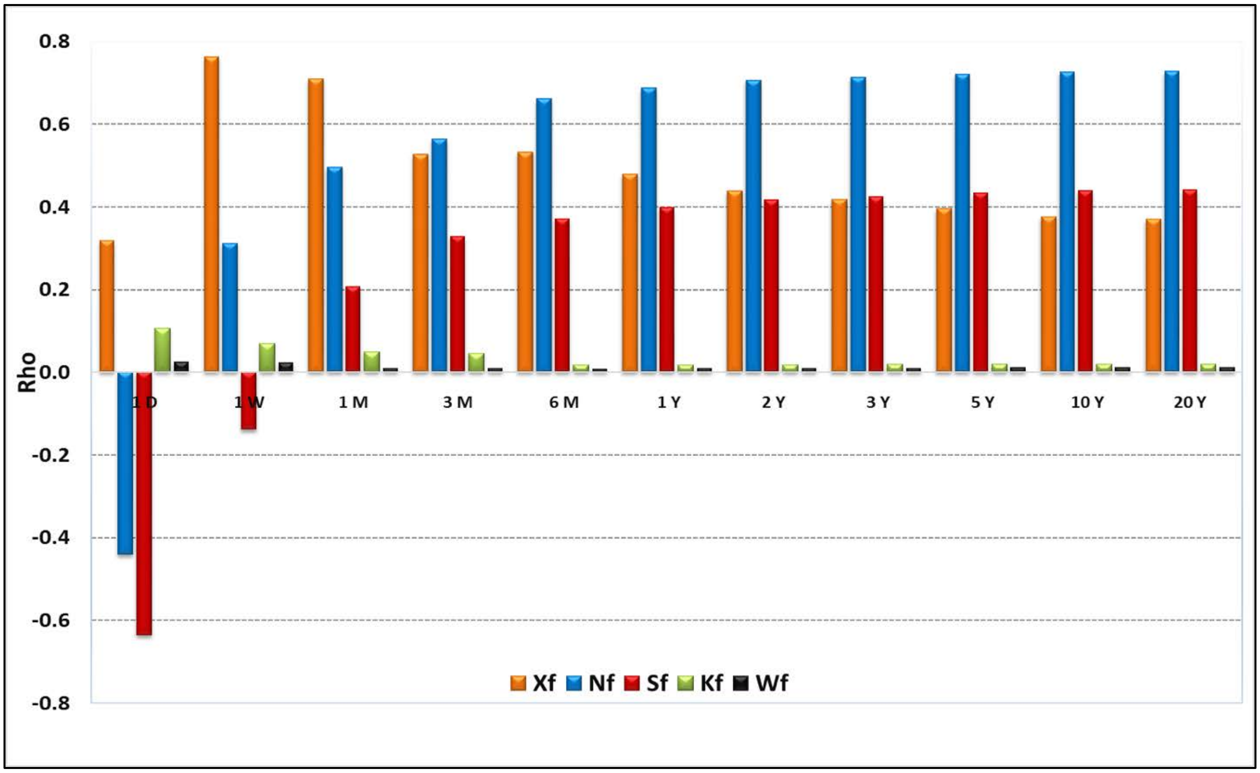

Fig 14: The impact of five pertinent parameters on NPV values for the 20-year well lifetime (K_m=0.01 mD).

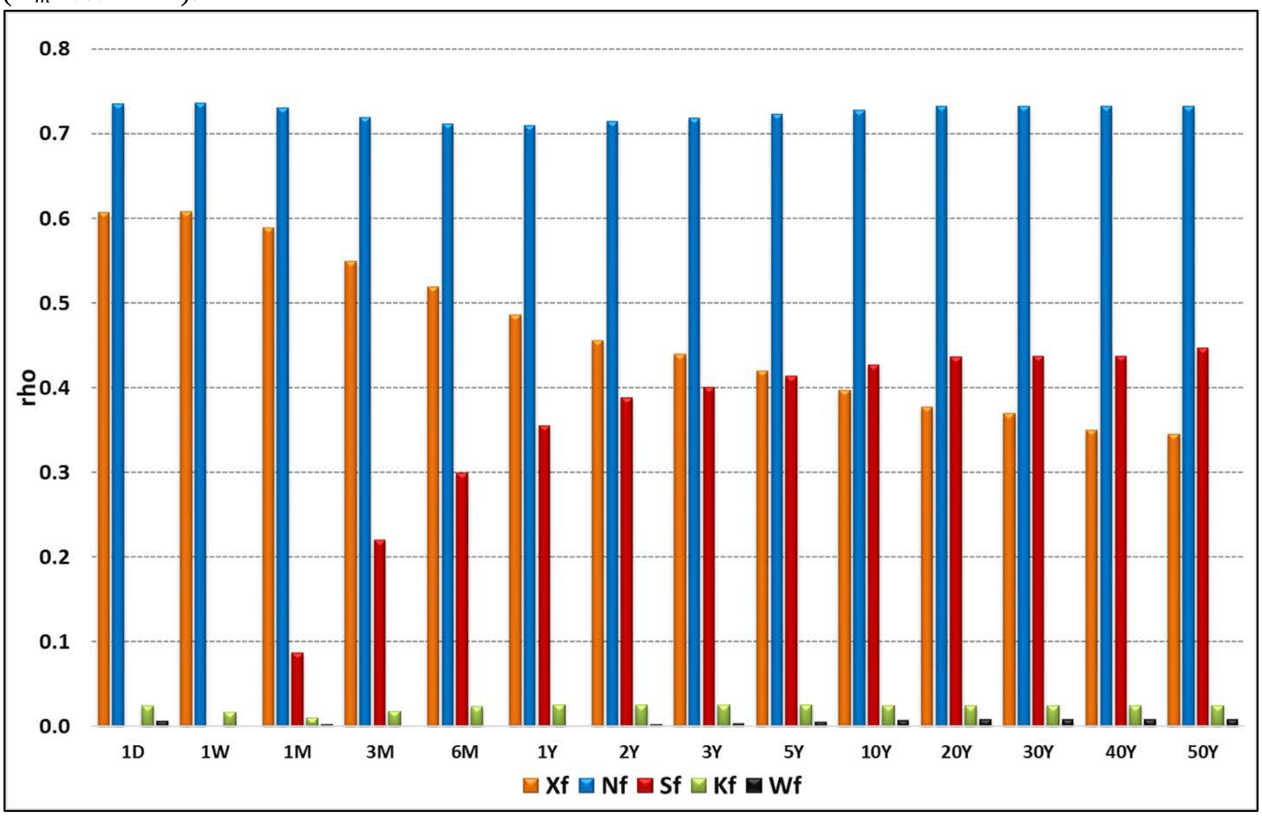

Fig 15: The impact of five pertinent parameters on FGPT over the 50-year well lifetime (K_m=0.001 mD).

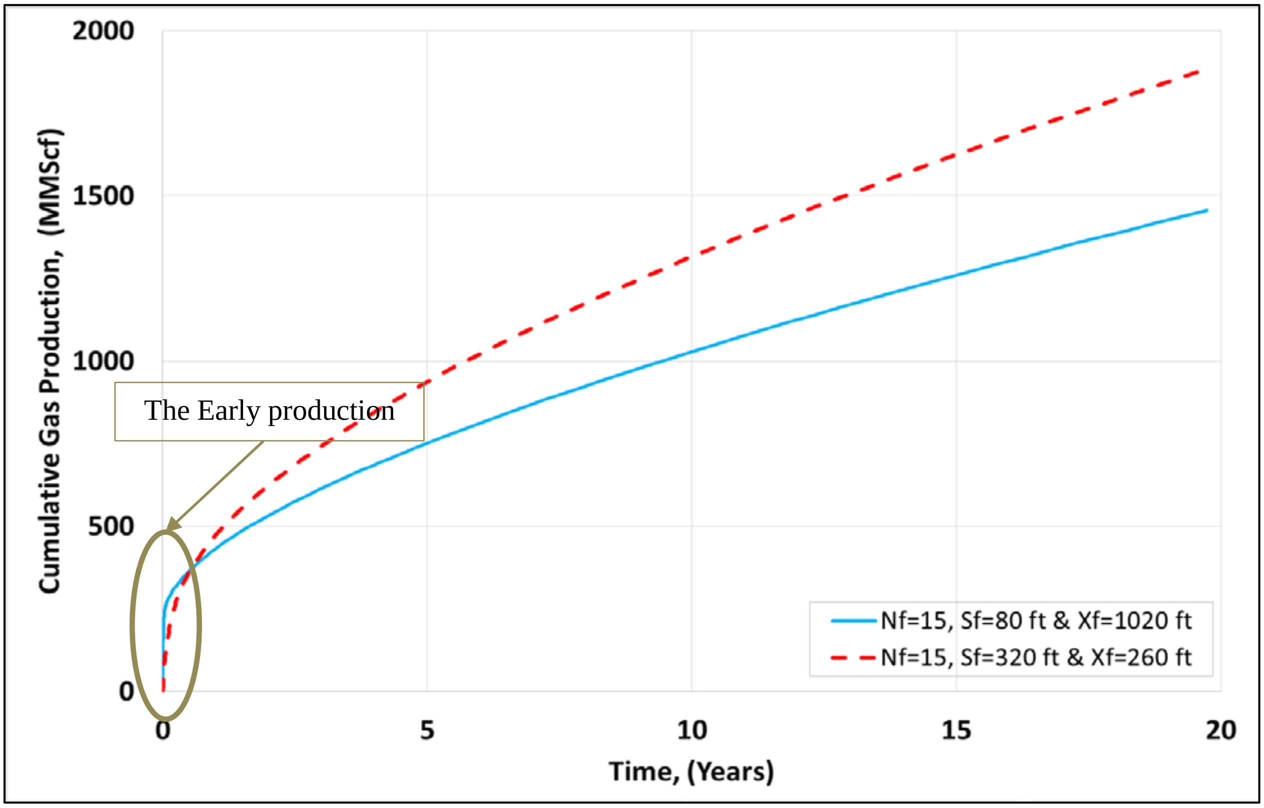

Fig 16: Cumulative Gas Production for two different MFHWs designs at K_m=0.001 mD.

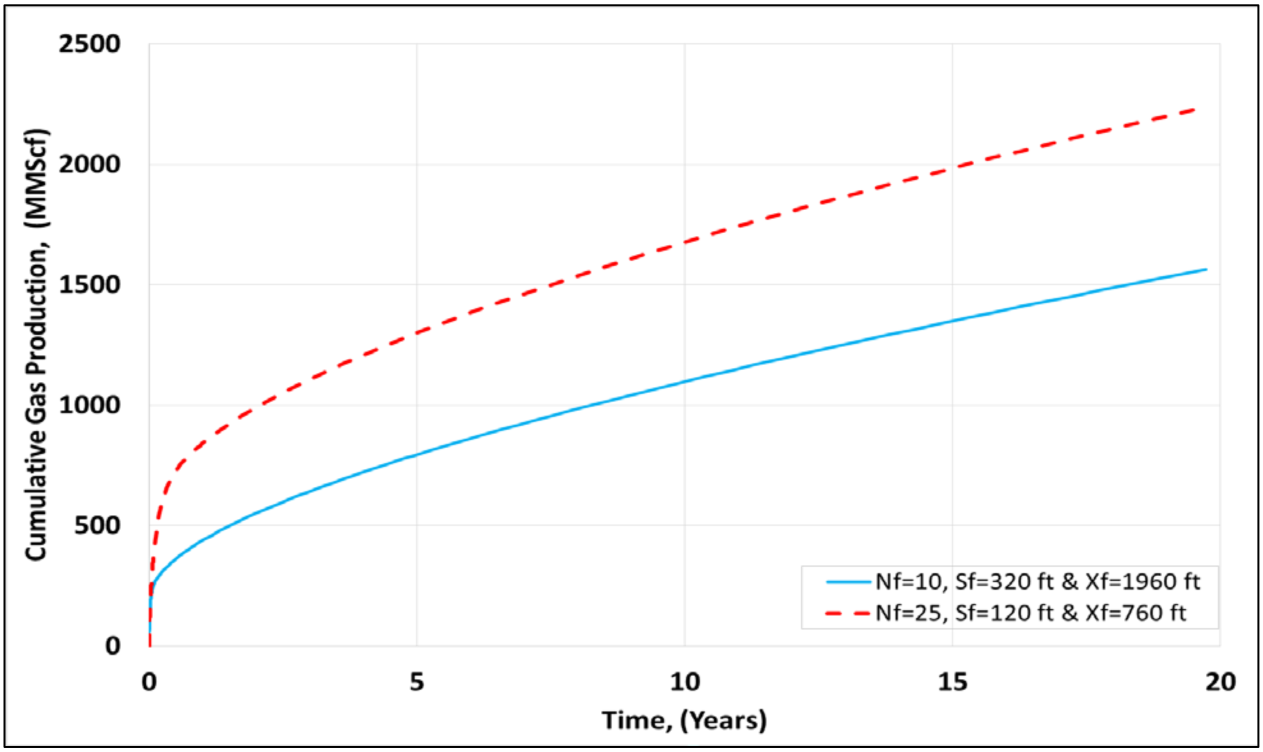

Fig 17: Cumulative Gas Production for two different MFHWs designs at K_m=0.001 mD.

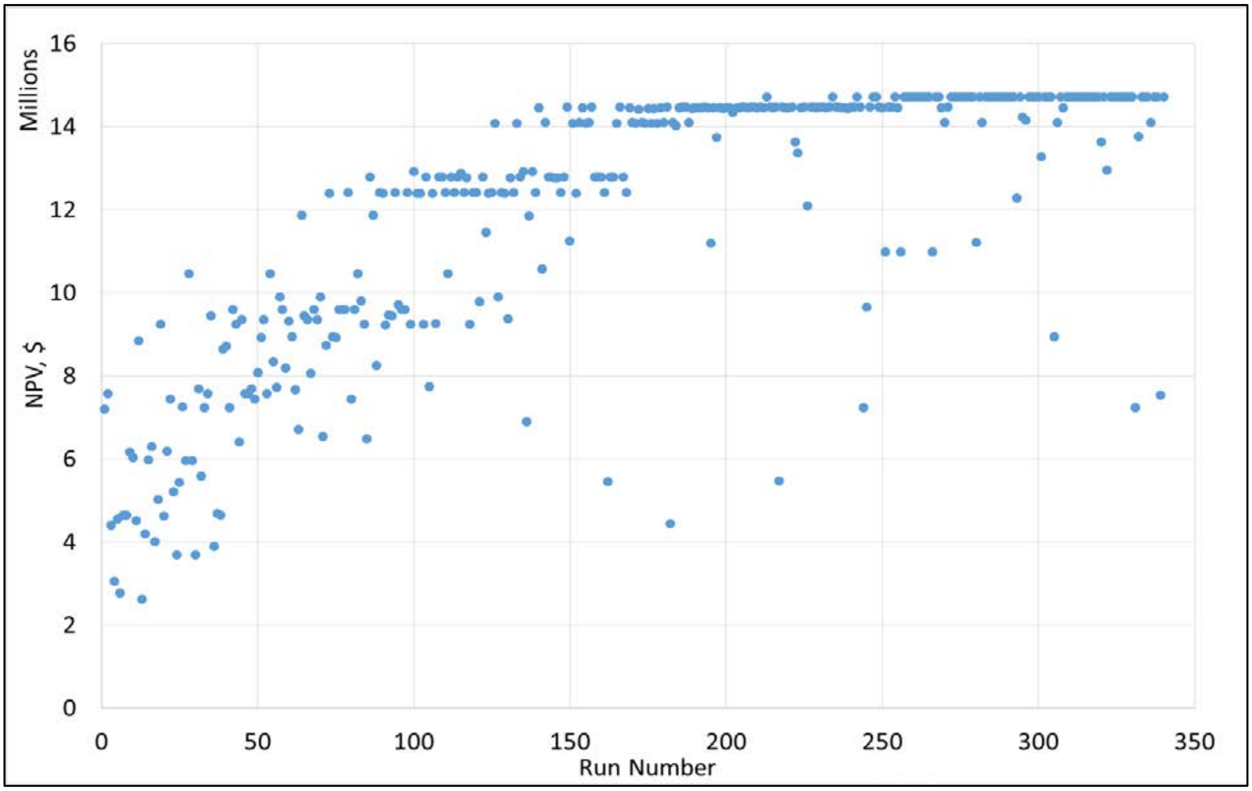

Fig 18: NPV values for 340 cases, performed by the optimizer to determine the optimum MFHW design, in the reservoir with K_m=0.01 mD.

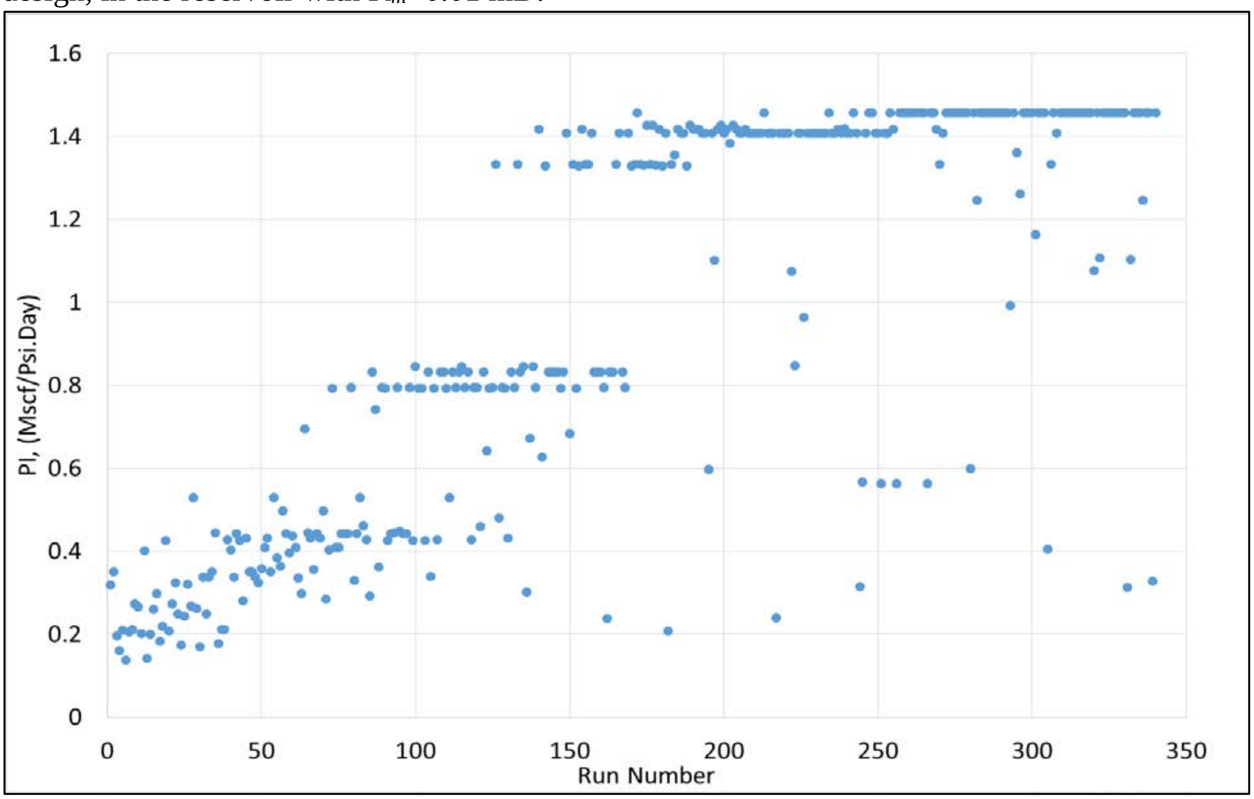

Fig 19: PI values for 340 cases, performed by the optimizer to determine the optimum MFHW design, in the reservoir with K_m=0.01 mD.